

## UTAH DIVISION OF AIR QUALITY MODIFIED SOURCE PLAN REVIEW

S. Gale Chapman, President  
Intermountain Power Service Corporation  
850 West Brush Wellman Road  
Delta, Utah 84624 RE:

Project fee code: N0327-010

REVIEW ENGINEER:

DATE:

NOTICE OF INTENT SUBMITTED: November 4, 2002 & March 24, 2003

PLANT CONTACT:

PHONE NUMBERS:

FAX NUMBER:

SOURCE LOCATION:

UTM COORDINATES:

CO PSD Major Modification to DAQE-049-02 at Unit 1 and 2  
Intermountain Generating Station

Millard County, Utah CDS-A, ATT, Title V, Title IV, NSPS

Milka M. Radulovic

April 30, 2003

Rand Crafts

(435) 864-6494

(435) 864-0994

850 West Brush Wellman Road Delta, Millard County, Utah

4,374.4 km Northing, 364.2 km Easting, Zone 12 datum  
NAD27

APPROVALS:

Peer Engineer \_\_\_\_\_

John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact \_\_\_\_\_

(Signature & Date)

**OPTIONAL:** In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. **THIS IS STRICTLY OPTIONAL!** If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307-415-5a through 5e or R307-415-7a through 7i.

**"Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application)."**

Responsible Official \_\_\_\_\_

(Signature & Date)

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**TYPE OF IMPACT AREA**

|   |                       |
|---|-----------------------|
| Attainment Area   | Yes                   |
| NSPS  | Yes                   |
| 40 CFR Part 60, Subpart Da (Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After September 18, 1978), and Subpart Y (Coal Preparation Plants) |                       |
| NESHAP  | No                    |
| MACT  | No                    |
| Hazardous Air Pollutants (HAPs)   | Yes (from combustion) |
| Hazardous Air Pollutants Major Source<br>(No HAPs involved in modification)   | Yes                   |
| New Major Source  | No                    |
| Major Modification  | No                    |
| PSD Permit  | Yes                   |
| PSD Increment (modeling)  | Yes                   |
| Operating Permit Program  |                       |
| Area Source   | No                    |
| Major   | Yes                   |
| Send to EPA   | Yes                   |
| Comment period  | 30-day                |

**FOR MODIFIED SOURCES**

The Notice of Intent is for a modification to an existing source. The following standards are applicable to this review:

|                                       |     |
|---------------------------------------|-----|
| NSPS applies to modification?         | No  |
| PSD review of entire source required? | Yes |
| NESHAPS applies to modification?      | No  |
| HAPs involved in modification?        | No  |
| TITLE V required for entire source?   | Yes |
| HAPs MAJOR for modification?          | No  |
| NONATT MAJOR for entire source?       | No  |

### Abstract

*Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 875 MW units (after uprate 950 MW approved in the DAQE-049-02), located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-049-02 to install NO<sub>x</sub> control system (overfire air) to accommodate the restriction on NO<sub>x</sub> emissions imposed by the Acid Rain Program regulations. In addition, IPSC is proposing:*

- Replacement-in-kind for the Boilers 1 & 2 low-NO<sub>x</sub> burners*
- To replace power supplies and motor drives to induced fans*
- To clarify and specify where surface-heating area was actually to be added in the Boilers 1 &*

2

*Projected emission changes from this project are from zero to about 4,000 to 6,000 tons decrease of NO<sub>x</sub> with concurrent increase of CO from zero to about up to 2,400 3500 ???tons. Other pollutants emission rates, stack mass flow, temperatures, air contaminant types, and concentrations of air contaminants will remain the same. This project represents a major modification under the Prevention of Significant Deterioration program since the proposed physical change can result in the significant emission increase for CO.*

*Air quality impact analysis of the CO maximum emission increases was performed and it showed that 1 and 8 hours impacts were well below significant impact levels. Furthermore, potential reduction in the target emissions of NO<sub>x</sub> is expected to improve visibility and expand available NO<sub>x</sub> increments.*

*Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y apply to this source. Boiler 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a major source of NO<sub>x</sub>, SO<sub>2</sub>, CO, and PM<sub>10</sub>. Title V of the 1990 Clean Air Act applies to this source. The Title V permit will be administratively amended prior to commencement of the operation of the control system.*

### Newspaper Notice

It has been determined that the conditions of the Utah Administrative Code R307-401-6 and the Federal rules have been met. The Executive Secretary intends to issue an Approval Order after a 30-day public comment period is held. This comment period is being held to receive and evaluate public input on the project proposed by Intermountain Power Service Corporation.

### I. DESCRIPTION OF PROPOSAL

IGS is a fossil fuel-fired steam-electric generating station that primarily uses coal as fuel for the production of steam to generate electricity. Both bituminous and subbituminous coals are utilized. Fuel oil and used oil are also combusted for start-up, flame stabilization and energy recovery.

IGS is a two-unit facility currently approved to operate at a rated capacity of 950 megawatts (MW). IPSC is in the process of performing the uprate to 950 MW per unit as approved through AO # DAQE-049-02. Approximately 5.6 million tons of coal and 600,000 gallons of oil will be used each year in the production of electricity. Boiler capacity will be rated at 6.9 million pounds per hour of steam flow at 2,822 psi and 777°F.

IGS has in place bulk handling equipment for the unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes of this equipment are required nor expected. No changes in the usage of other raw materials or bulk chemicals are required nor expected.

Note that process diagrams have previously been submitted, and no changes from those are proposed here.

#### **PROPOSED CHANGES:**

Rectified power drives and motors for induced fan motors need to be replaced due to obsolescence. IPSC has approval to increase surface area to the main boilers, and we are clarifying the location. IPSC is also requesting approval to install overfire air ports in each boiler to replace our current operating strategies for controlling NO<sub>x</sub> emissions. These changes are needed specifically for reliability, performance and/or routine maintenance needs, will not increase plant capacity beyond the current approved project. In addition, IPSC is performing replacement in kind of Boiler #1 & #2 Low-NO<sub>x</sub> burners.

#### **BACKGROUND**

On January 11, 2002, the Utah Division of Air Quality (UDAQ) issued to Intermountain Power Service Corporation (IPSC) an approval order (DAQE-049-02) to make certain modifications to the Intermountain Generating Station (IGS). On September 23, 2002, IPSC submitted a Notice of Intent (NOI) to clarify and adjust the scope of those modifications, known as the Dense Pack Uprate Project, as well as receive permitting for other changes. This NOI is being used to summarize the Dense Pack Project and certain other changes previously approved by UDAQ.

Approval Order DAQE-049-02 allowed IPSC to make certain changes provided IGS operated those changes as a minor modification pursuant to actual to future actual provisions under Utah's Prevention of Significant Deterioration (PSD) rules. Changes allowed under that Approval Order as described in its original NOI included:

- Increasing heat input to main boilers
- Adding surface area to main boilers
- Replacing each unit high pressure turbine with new technology turbines
- Replacing certain relief valves with safety valves in main boilers
- Adding wall rings to each scrubber module
- Adding helper cooling towers and cooling system enhancements
- Enhancements to generators, isophase & motor buses, transformers, boiler feed pumps, high

pressure lines, control systems, and other similar changes.

**The September 23, 2002 NOI sought:**

To clarify where surface area was actually to be added in main boilers  
To replace power supplies and motor drives to induced fans  
Replacement-in-kind acknowledgment for low-NO<sub>x</sub> burners  
To add overfire air ports to main boilers for NO<sub>x</sub> control.

Full descriptions of those changes were discussed in that NOI and in subsequent letters, e-mails, and meetings between IPSC and DAQ staff. Additionally, in order to assess how OFA affects both NO<sub>x</sub> and CO emissions, an experimental AO was issued on February 14, 2003 to allow installation and testing of an OFA system on Unit One.

**PERMIT OPTIONS**

Of particular interest for this NOI is how to treat the permitting for overfire air (OFA). IPSC initially sought to have OFA permitting as a *minor modification under certain PSD provisions*. However, once testing of the OFA system is complete, the results are likely to show that CO may increase in major net significant amounts (greater than 100 tons per year) when NO<sub>x</sub> is controlled to low emission rates.

For the dense pack modifications, IPSC chose to modify combustion for NO<sub>x</sub> control during increased heat input, rather than utilize technological add-on controls. Combustion in the boiler was fine-tuned to optimize performance against NO<sub>x</sub> emissions using such methods as burner-out-of-service, excess oxygen control, fuel management, and other boiler operational changes.

Although such practices have been successful, IPSC believes that replacing this combustion methodology with technical add-on controls would better optimize boiler performance and control of NO<sub>x</sub> emissions.

The use of OFA will allow IPSC to control NO<sub>x</sub> without a significant net increase due to the dense pack modifications. However, IPSC believes it is possible that certain OFA configurations can cause a net significant increase in CO emissions. Therefore, IPSC seeks permitting of OFA as a major modification for CO under PSD.

**PRODUCTION SUMMARY:**

IPSC is in the midst of an ongoing uprate project that will increase generation capacity from 875 to 950 MWhe, with steam flow design increasing from 6.2 to 6.9 million pounds per hour. Design heat input will increase from 8,500 to 9,225 million Btu per hour, requiring the use of 5.6 million tons of coal each year. See AO #DAQE-049-02 and its corresponding NOI for details. Nothing in this NOI is intended to change those production aspects of the previously approved uprate project.

**EMISSION CHARACTERISTICS:**

The composition and physical characteristics of emissions resulting from the proposed modifications are not expected to change with the exception of carbon monoxide (CO), which may increase by a net significant amount. Other pollutant emission rates, chimney mass flow, temperature, air contaminant types, and concentration of air contaminants will remain the same proposed in the uprate project. The current pollution control devices (PCD) include low-NO<sub>x</sub> burners, fabric filters and wet scrubbers.

Specifically, it is possible for CO emissions to increase as over-fire air (OFA) is used to decrease NO<sub>x</sub> emissions. When NO<sub>x</sub> emissions are fully minimized utilizing OFA, IPP believes that CO emissions can increase from 1989.6 tons per year (as calculated by AP-42- EPA's compilations of emission factors) to 5,171.9 tons per year (as projected by boiler performance modeling).

The following emission rate parameters are provided as required:

| Parameter         | Current Before PCD | Current After PCD | Resulting change after modifications |
|-------------------|--------------------|-------------------|--------------------------------------|
| Particulates      | 96,000 lbs/hr      | 50 lbs/hr         | none                                 |
| Nitrogen Oxides   | 0.42 lbs/MMBtu*    | 0.42 lbs/MMBtu    | 0.34 lbs/MMBtu minimum               |
| Sulfur Dioxide    | 1.8 lbs/MMBtu      | 0.06 lbs/MMBtu    | none                                 |
| Carbon Monoxide   | 0.022 lbs/MMBtu**  | 0.022lbs/MMBtu    | ***0.064 lbs/MMBtu maximum           |
| Temperature       | 325 F              | 120 F             | none                                 |
| Stack Gas Volume  | 130,000,000 scfh   | 130,000,000 scfh  | none                                 |
| Hydrochloric Acid | 0.67 lbs/hr        | 0.02 lbs/hr       | none                                 |
| Hydrofluoric Acid | 0.14 lbs/hr        | 0.004 lbs/hr      | none                                 |
| Antimony          | 0.007 lbs/hr       | 0.000008 lbs/hr   | none                                 |
| Arsenic           | 0.03 lbs/hr        | 0.00006 lbs/hr    | none                                 |
| Beryllium         | 0.0009 lbs/hr      | 0.0000005 lbs/hr  | none                                 |
| Cadmium           | 0.001 lbs/hr       | 0.00001 lbs/hr    | none                                 |
| Chromium          | 0.06 lbs/hr        | 0.0001 lbs/hr     | none                                 |
| Cobalt            | 0.006 lbs/hr       | 0.00001 lbs/hr    | none                                 |
| Lead              | 0.013 lbs/hr       | 0.00003 lbs/hr    | none                                 |
| Manganese         | 0.016 lbs/hr       | 0.00005 lbs/hr    | none                                 |
| Mercury           | 0.0001 lbs/hr      | 0.00001 lbs/hr    | none                                 |
| Nickel            | 0.009 lbs/hr       | 0.00005 lbs/hr    | none                                 |
| Selenium          | 0.005 lbs/hr       | 0.00065 lbs/hr    | none                                 |

NOTES:

\*NO<sub>x</sub> emissions are estimated AFTER low NO<sub>x</sub> combustion.

\*\*Current CO emissions based upon AP-42 factors.

\*\*\*modified CO emissions based upon engineering design.

Any increase in CO is unlikely to be this large. Since no increased fuel flow is predicted for the changes proposed in this NOI, an AP42 calculation would show no increase in CO. However, it is generally acknowledged that combustion NO<sub>x</sub> emission controls do increase CO. As a

practical matter, we have shown an increase from AP-42 calculations to an average rate based upon engineering design judgment.

Carbon monoxide (CO) emission rates are provided based upon two different derivations. The current CO rate of 0.022 lbs/MMBtu is based upon AP-42 calculations. The projected CO rate is based upon combustion modeling for overfire air. The increase from a current calculated rate to a projected rate is about 3,500 tons. Since IPP do not have no actual CO monitoring data, IPSC has pulled from its archived files the performance data from the IPP boiler acceptance testing. This data indicates that the actual current CO rate of emissions is about 0.041 lbs/MMBtu, rather than 0.022 lbs/MMBtu, which would project an increase of about 2,400 tons of CO in a worst case change, where NO<sub>x</sub> is concurrently decreasing 4,000 to 6,000 tons????per boiler???

#### **Pollution Control Device Description:**

Present pollution control device equipment for combustion for the Unit 1 and 2 boilers includes dual-register low NO<sub>x</sub> burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The low NO<sub>x</sub> burners provide a nominal 60 percent reduction in potential combustion NO<sub>x</sub> concentration, the baghouse filters operate at nominal 99.95 percent efficiency, and the wet scrubbers operate at nominal 90 percent efficiency. Control equipment for the handling and transfer of solid material include dust collection filters.

#### **Pollution Control Device Upgrade:**

The project includes the addition of overfire air (OFA) ports and replacement or repair of dual register low NO<sub>x</sub> burners.

#### **Description of the Overfire Air (OFA) System and Control Devices.**

The over-fire air (OFA) system at the Intermountain Generating Station (IGS) is being provided by Babcock Power, Inc. (BPI). It consists of two rows of OFA ports located on the elevation immediately above the top burner levels on both the front (south) and rear (north) sides of the boiler. Each row consists of eight, identical, OFA ports with one port located over each of the six burner columns (column ports) and one port located on each end of the OFA rows near the side walls of the boiler (wing ports).

Air to the OFA system is provided by the Secondary Air (SA) system. A feeder duct extends from each SA header duct to the corresponding OFA header through which secondary air is admitted to the OFA headers. Each OFA feeder duct includes isolation dampers operated by Jordan rotary electrical drives.

OFA airflow to the boiler is admitted and controlled through the OFA port dampers. Each OFA port is partitioned into separate 1/3 and 2/3 sections. Airflow, through each partition, is controlled by port dampers located in each partition. The four, 1/3 port dampers for an OFA row half are connected or ganged together for simultaneous operation by a Jordan rotary electrical drive. The same configuration is implemented for the 2/3 port damper sets. This creates a total of four, 1/3 port dampers/drives and four, 2/3 port dampers/drives for air flow control to the

boiler.

Control and monitoring of all OFA damper drives will be done by the IGS combustion control system. Additionally, an array of three Air Monitor Corporation VOLU-probes and thermocouples will measure OFA mass flow through each of the feeder ducts.

#### **Description of the Proposed Control Strategy**

Note: All boiler load set-point values and the OFA secondary air ratio set-point curve, described below, are initial values. These values will be revised based on the results of the commissioning performance tests. Please refer to documentation to be provided by BPI.

OFA is most effective controlling NO<sub>x</sub> formation at unit loads above 60% of the rated load of 950 MW. When utilized at the 60% load point and above, OFA flow will be accomplished by the combination of opening OFA feeder and port dampers and decreasing the combustion air damper positions, so as to maintain target total SA flow based on unit load.

The OFA port and feeder duct dampers are not modulating and will be operated either fully open or fully closed (except for biasing of the open position to achieve balanced O<sub>2</sub> distribution across the burner front). SA airflow to the OFA system is attained by simultaneously decreasing the openings of all the combustion air dampers feeding each of the burner elevations that are in operation. This decrease is to be superimposed on the existing automatic control biasing of each elevation combustion air in accordance with pulverizer loading.

This SA damper control is additive to the existing bias required to change burner airflow in proportion to the individual pulverizer load. The action of the sum of both biases will result in less secondary air directly to the burners, as OFA is being introduced, but the relative secondary air distribution between burner elevations will remain unchanged.

BPI will provide a set-point curve showing the desired ratio of OFA flow to secondary airflow as a function of boiler load. These values will be confirmed or revised based upon actual tests. The OFA port relative open area sizes, 1/3 and 2/3, are calculated to provide the correct velocity of the OFA to attain the proper penetration of the OFA into the combustion region of the furnace above the burners. All ports of a given kind, 1/3 or 2/3, will open or close following a program designed to open the correct area to roughly produce the proper penetration velocity as the OFA air flow rate changes with boiler load. The initial program is as follows:

|                         |                                  |
|-------------------------|----------------------------------|
| 0 to 60% boiler load:   | All 1/3 and 2/3 ports closed     |
| 60 to 75% boiler load:  | 1/3 ports open, 2/3 ports closed |
| 75 to 90% boiler load:  | 1/3 ports closed, 2/3 ports open |
| 90 to 100% boiler load: | 1/3 ports open, 2/3 ports open   |

An individual manual/automatic and bias station per port group damper drive will be provided.

#### **Target Operating Parameters for OFA Design**

The OFA modifications shall provide for a continuous boiler rating of 6,900,000-lbs/hr output at 1005°F superheat and 1005°F reheat temperature under normal operating conditions. These modifications shall include the design, fabrication and installation on both IGS Units 1 & 2 for an overfire air system capable of providing a reduction in NO<sub>x</sub> emissions of 15% and consistent NO<sub>x</sub> emissions of less than 0.40 lbs/MMBtu under all operating modes.

Of particular interest to IPSC are the performance parameters associated with operation at 950 Megawatts gross generation (6.75 MMlbs/hr steam flow). These include:

- a. Total NO<sub>x</sub> output of 0.40 lbs/MMBtu or less and an overall reduction of 15%. Current maximum average of 0.45 lbs/MMBtu.
- b. Superheat and reheat temperatures as well as NO<sub>x</sub> emissions must remain within the contract stated acceptable ranges throughout the test.
- b. Impact on average unburned carbon (LOIs) and carbon monoxide (CO) concentrations within the boiler.
- d. The above operational parameters shall be verified in a steady state operational test within 30 days of installation. Steady state operation shall be defined as stable and reliable operation at and within the following operating conditions and ranges for a period of at least 7 days:
  - 7 pulverizers in service (E and G Pulverizers alternately out-of-service).
  - Excess air to be controlled between 2.5 to 3.2%.
  - Superheat and convection surfaces maintained at 80-85% cleanliness
  - Boiler tube maximum allowable metal temperatures must not be exceeded.
  - Turbine throttle pressure of 2375 psi.
  - Furnace cleanliness maintained at 85-90% actual cleanliness.
  - Superheat attemperator spray flow at or above 50,000lbs/hr
  - Reheat attemperator spray flow at 0 lbs/hr

NOTE: These are target parameters only for purposes of OFA design and performance evaluation, and in no way IPSC intended to limit boiler operation in any way.

#### **EMISSION POINT:**

The present emission point for the IGS boilers is a lined chimney that discharges at 712 feet above ground level (5,386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude.

#### **SAMPLING/MONITORING:**

Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide, and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt

load). Monitoring will remain unchanged. Other emissions not directly monitored are calculated using engineering judgments, emission factors, and fuel analyses.

#### **OPERATING SCHEDULE:**

Operation at IGS is 24 hours per day, seven days per week.

#### **MODIFICATION SPECIFICATIONS and CONSTRUCTION SCHEDULE:**

##### **a. Induced Fan Drive Power Supply Obsolescence & Replacement**

There are four induced draft (ID) fans for each generator at the Intermountain Generating Station. The fans are centrifugal airfoil, double width, double inlet design driven by synchronous motors through variable frequency drives. The flow modeling has shown the best approach to correcting our obsolescence problem may be to replace our current power drives with new induced pulse width modulation technology. Such a change would require motor replacements. The existing variable frequency drives are of 1980 vintage, no longer manufactured, require increasing maintenance, certain critical repair parts are no longer available, and frequently fail, although such failures do not currently impact station operation due to fan redundancy. The variable frequency drives are scheduled for replacement beginning in 2003. Replacement of the variable frequency drive systems will not include modifications of the existing fans and no change beyond approved capacity would result from the possible drive and motor horsepower change out. We are therefore requesting approval accordingly.

##### **b. Changes to Approved Boiler Modifications**

The steam generators at IGS are scheduled for modification to accommodate the 950 MW rating. Previously approved but uncompleted boiler modifications included the addition of preheat steam tubes to the convective pass of each boiler. Due to latest modeling and operational data, this NOI proposes to change those modifications to the radiant section of the boiler, which will include the addition of platen superheater surface. The 36-platen superheater pendants, in each boiler, are scheduled to be lengthened by approximately 8 feet from their present approximate 40-foot length. The purpose of these changes was for better combustion control. These proposed changes are still on track for Unit 1 in March 2003, and Unit 2 in March 2004, meeting the construction schedule originally set forth under DAQE-049-02.

##### **c. Low NO<sub>x</sub> Burner Maintenance & Replacement**

IPSC proposes to replace the existing burners as needed in future years. Burners have not met their design life and need to be replaced or rebuilt. The replacement or rebuild of the present low-NO<sub>x</sub> burners is considered as replacement-in-kind, as we do not propose to increase heat input through the new burners from what is currently approved. The current burners have already been shown to accommodate heat input rates of the current uprate modification. This NOI requests UDAQ to make an affirmative determination that the replacement of low-NO<sub>x</sub> burners with new low-NO<sub>x</sub> burners can be considered replacement-in-kind. Burner maintenance and repair for Unit 1 and burner replacement for Unit 2 will begin in 2004 and continue through

2008 in a multi-staged process.

**c. Overfire Air Ports**

A multiport overfire air system will be added to ensure stable operation in accordance with specified emissions limits. IPSC currently uses a combustion tuning methodology for NO<sub>x</sub> control that we find is costly and somewhat haphazard. Overfire air is also needed, in part, to accommodate the restriction on NO<sub>x</sub> emissions imposed by Acid Rain regulations that were promulgated based upon the Clean Air Act Amendments of 1990. Specifically, in 2007 Acid Rain requirements impose a 0.46 lb/MBtu annual cap for NO<sub>x</sub> emissions on IPP. Since an early election was filed for IPP, this new limit was delayed. Current forecasts of coal quality indicate that without overfire air, the new Acid Rain limit could be difficult to attain.

The overfire air system will redirect approximately 10 -20 percent of total combustion air to a staged system of ports located directly above the top row of burners. When OFA is utilized to minimize NO<sub>x</sub> emissions as much as possible, CO emissions may increase by a net significant amount.

A full description of the OFA system and its operation has already been filed with the UDAQ. In fact, IPSC is currently installing and will test an OFA system on Unit One as allowed by an experimental approval order. The results of the test will help confirm potential CO increases and certain operational aspects of OFA.

**d. Distributed Control System**

IPSC had proposed replacement and upgrade of the distributed control system at IGS in the April 2001 NOI. However, AO #DAQE-049-02 did not specifically identify the DCS replacement, except for the description in the AO abstract as "other similar changes." For clarity, IPSC wishes to have the DAQ specifically identify the DCS project in the AO, and treat this NOI as such request. Certain control systems will be upgraded as an integral part of the uprate modification (i.e., new turbine, boiler modifications, OFA system) and are considered part of those modifications. However, IPSC is proposing to upgrade all corresponding operating control systems as well. The Intermountain Generating Station is controlled by several subordinate systems. These systems include a coordinated control system, a burner management system, a combustion control system, a turbine electro-hydraulic control system, a turbine supervisory system as well as several plant data acquisition and status display systems. Components within these systems are becoming increasingly hard to obtain from either primary or secondary manufacturers. Although there have been no system failures that have caused forced outages, these control systems are now causing reliability concerns due to the unavailability of key hardware.

The existing control systems are scheduled to be replaced beginning in the 2004 spring outage. The various control systems will be replaced with a centralized, distributed control system in a phased approach over a several year period to reduce the impact on generation capability. The current schedule shows this project being completed in the spring of 2007.

## **Applicability Determinations**

### **Overfire Air.**

The installation of overfire air ports to the Units One & Two boilers can be expected to cause a decrease in NO<sub>x</sub> with a concomitant increase in CO. This follows a sliding relationship; i.e., if NO<sub>x</sub> levels are maintained, no CO increase can result. If NO<sub>x</sub> is minimized to the greatest extent possible, CO may rise accordingly. IPSC predicts that normal operation will show a slight decrease in NO<sub>x</sub> with the use of overfire air, resulting in a small increase in CO.

Nothing in this discussion or NOI is meant to indicate any requirement that IPSC must operate the overfire air and Low-NO<sub>x</sub> burners to fully minimize NO<sub>x</sub>. IPSC's intent in adding further NO<sub>x</sub> controls is to balance performance with environmental control. IGS intends to continue to operate in such a manner that maximizes performance, yet still meets environmental limits as mandated by regulation and permit. This means that NO<sub>x</sub> will be controlled to meet short term thirty-day rolling average limits, as well as the annual WEPCO requirements outlined in the current AO.

### **New Source Performance Standards.**

IGS operates as a New Source Performance Standard (NSPS) power plant, regulated under Title 40 of the Code of Federal Regulations, Part 60, Subpart Da. The proposed changes do not trigger NSPS applicability. "Modification" is defined at 40 CFR 60.14 to include any change in operation of a source that increases the maximum hourly emissions of a Part 60 regulated pollutant above the maximum achievable during the previous five years. (See 40 CFR 60.14(h)). Even though the use of overfire air ports to reduce NO<sub>x</sub> can increase carbon monoxide (CO), CO is not a regulated pollutant under NSPS Subpart Da which is applicable to IGS.

### **Prevention of Significant Deterioration.**

IGS was constructed under Prevention of Significant Deterioration (PSD) permits, and with the exception of possible CO increases, none of the changes proposed herein are a major modification for PSD purposes. Based upon boiler performance modeling, CO emissions are expected to increase by a net significant amount (greater than 100 tons per year). Those projected CO increases have been modeled for possible air impacts and have been shown they do not cause or contribute to a violation of a NAAQS, PSD increment, or adverse Class I impact. Those modeling results have already been submitted to UDAQ.

### **Modeling**

CO modeling was performed for the total potential emission of CO to evaluate if increases do not cause or contribute to a violation of a NAAQS, PSD increment, or adverse Class I impact. For the worst case CO short term emission rate of 1200 lbs/hr, ISC modeling shows results of 80 ug/m<sup>3</sup> for 1 hour and 20 ug/m<sup>3</sup> for 8 hours. This is well below the modeling significant levels of 2000 and 500 ug/m<sup>3</sup>, respectively, confirming no adverse contribution or violation.

**Best Available Control Technology (BACT).**

IGS was constructed under a PSD permit which required BACT. Since the CO emissions increases may trigger a major PSD modification, a Top Down CO BACT analysis was performed.

**Top-Down BACT Process**

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps are:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

Each of these steps has been conducted for CO and is described below.

Potential control technologies for CO were identified from a number of sources including the EPA RBLC database, control technology vendors, technical journals and web sites, and other recently issued permits

**CO Analysis**

The BACT analysis for CO is presented below.

**Step 1 – Identify All Control Technologies**

Only two control technologies have been identified for control of CO on coal-fired boilers:

Catalytic oxidation

Combustion controls

Catalytic oxidation is a post-combustion control device that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

**Step 2 – Eliminate Technically Infeasible Options**

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO emitting from primarily combustion turbines firing natural gas. This alternative, however, has never been applied to a PC-fired unit so this technology has not been demonstrated in practice in this application.

For sulfur containing fuels, such as coal, an oxidation catalyst will convert SO<sub>2</sub> to SO<sub>3</sub> and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system. Generally, oxidation catalysts are designed for a maximum particulate loading of 50 milligrams per cubic meter (mg/m<sup>3</sup>). The proposed IPP boilers will have a particulate loading upstream of the fabric filter in well above this value. In addition, trace elements present in coal, in particular

chlorine, are poisonous to oxidation catalysts. There are no catalysts developed that have or can be applied to PC-fired boilers due to the high levels of PM and trace elements present in the flue gas.

Although the catalyst could be installed downstream of the fabric filter where the concentration of PM in the flue gas is much lower than at the outlet of the boiler, the flue gas temperature at that point will be approximately 300°F. This is well below the minimum temperature required (600°F) for operation of oxidation catalyst. The flue gas would have to be reheated, resulting in significant unfavorable energy and economic impacts.

For these reasons, as well as the generally low levels of CO in PC-fired units, no PC-fired boilers have been equipped with oxidation catalysts. Use of an oxidation catalyst system in the PC-fired boiler is thus considered technically infeasible. Thus, this alternative cannot be considered to represent BACT for control of CO.

#### Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, combustion control is the only remaining technology for this application.

#### Step 4 – Evaluate Most Effective Controls and Document Results

There are no environmental or energy costs associated with combustion control.

#### Step 5 – Select BACT

Based on the above analysis, a Good Combustion Practice (GCP) for CO is selected as BACT. IPSC has provided a detailed discussion on what GCP entails for boiler operation utilizing OFA.

With regard to CO, BACT can only be provided through the application of good combustion practices (GCP), which is already in place, and is intimately related to best boiler performance, a strong business incentive. No other technological controls are available for CO in coal-fired boilers.

IPSC has provided a proposal on how GCP can be implemented, and the testing of OFA will help determine the parameters by which GCP can be verified.

Overfire air is needed, in part, to accommodate the restriction on NO<sub>x</sub> emissions imposed by Acid Rain regulations that were promulgated based upon the Clean Air Act Amendments of 1990. Specifically, in 2007 Acid Rain requirements impose a 0.46 lb/MMBtu annual cap for NO<sub>x</sub> emissions on IPP. Since an early election was filed for IPP, this new limit was delayed. Current forecasts of coal quality indicate that without overfire air, the new Acid Rain limit could be difficult to attain. A multiport overfire air system will be added to ensure stable operation in accordance with specified emissions limits. The overfire air system will redirect approximately 10-15 percent of total combustion air to a staged system of ports located directly above the top row of burners. The overfire system will be designed for operation with newer technology burners expected to eventually replace the existing burners as needed in future years. This NOI